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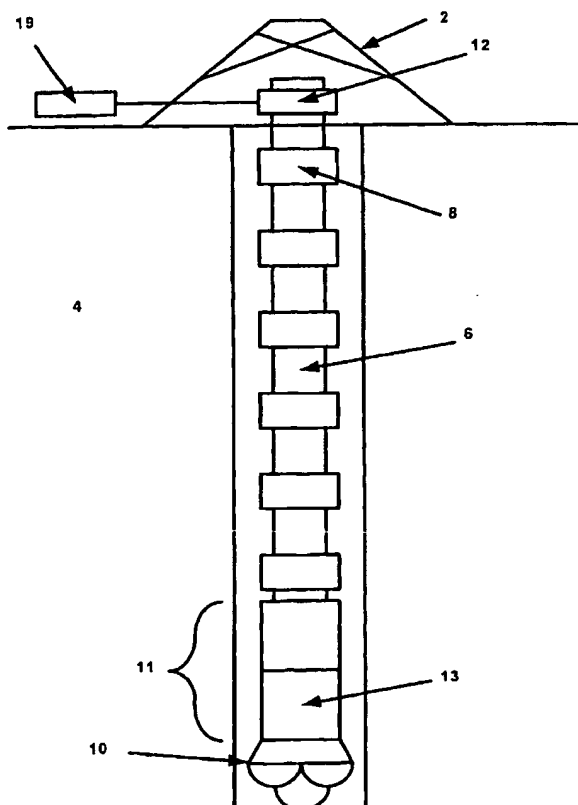
(57) Abstract: A method of acoustic telemetry in a drill string in a wellbore, comprises transmitting an acoustic signal related to a parameter of interest from a transmitting location into the drill string. The signals propagated through the drill string are detected at a receiving location, where the detected signals include noise. A drill string transfer matrix is determined defining the propagation of signals through a transfer interval between the receiving location and the transmitting location. The detected signals and the drill string transfer matrix are used for obtaining an estimate of the acoustic signal.

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METHOD OF DETECTING SIGNALS IN ACOUSTIC DRILL STRING TELEMETRY

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BACKGROUND OF THE INVENTION

Field of the Invention

This invention is in the field of signal processing, and is more specifically
10   directed to acoustic drill string telemetry.

Description of the Related Art

The petroleum industry relies heavily on the operation of drilling into the earth,

both on land and offshore, in the exploration for and production of petroleum products.

15   Over the years, the more readily found and accessible petroleum reservoirs have of

course been discovered and depleted first. As a result, the exploration and production

operations must necessarily concentrate to a greater degree on less accessible and less

readily discoverable reserves. In order to reach these locations, the depths of drilling

have increased, the locations at which drilling takes place have become increasingly

20   difficult and less accessible, and the drilling operations have necessarily become more

complex. Accordingly, drilling operations in the search for and production of petroleum

products have become more expensive, with this trend likely to continue in the future.

Because of this increasing cost, the accuracy and efficiency of the drilling operation is

becoming even more important.

25   The success and efficiency of the drilling operation depends to a large degree on

the quantity and quality of information that the drilling operator has about the sub-

surface structure into which the drilling is taking place, and also about parameters

concerning the operation of the drill bit as it proceeds into the earth. Many techniques

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for acquisition and communication of such information have been tried and used in the industry.

A system which utilizes the drill string as a medium for the transmission of data is referred to as acoustic telemetry or stress wave telemetry. Acoustic telemetry systems are known in the art. For example U.S. Pat. No. 5,477,505 to Drumheller and U.S.Pat. No. 5,303,203 to Kingman describe such systems. The typical system includes transmitters, such as solenoids, eccentric motors, and piezoelectric transducers, which intentionally vibrate the drill string in a manner corresponding to the desired data. These data may include information concerning drilling parameters and formation parameters. In the case of stress wave telemetry the desired information is obscured by undesirable bit and drilling noise that is also transmitted through the drill string.

It has been discovered that vibrations, whether from the drill bit itself or intentionally generated by transmitters, are not communicated through the drill string in an ideal manner, due to the non-ideal response of the drill string to such vibrations. Conventional drill strings, which consist of a number of lengths of drill pipe joined by pipe joints, inherently have frequency domain stopbands that attenuate acoustical signals at the stopband frequencies. This frequency-dependent attenuation can severely distort some signals. Other factors also distort the vibrations communicated along a drill string from downhole to the surface. Such factors include noise generated by the drilling fluid, or mud, which is conventionally pumped through the drill string at relatively high pressures. This high pressure flow of fluid causes significant vibrations in the drill string. Other devices in the drilling operation, such as bearings in the swivels at the top of the drill string, the rattling of chains which turn the kelly bushing, or the motor in a top drive drilling arrangement, and the slap of the casing against the drill string or well bore, also generate significant acoustical vibrations which are

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received by and transmitted along the drill string. These vibrations are superimposed upon the desired data signal, and will accordingly be detected at the top of the drill string by such detectors as are attempting to detect the data signal transmitted from the downhole location.

5   Considering the vibrations generated by a transmitter as "signal" and the vibrations generated by the drill bit and the other vibrations caused by drilling mud flow and the mechanical sources discussed in the prior paragraph as "noise", it has been found that the amplitude of the noise can be substantially greater than the signal amplitude. Noise at this level not only clouds the analysis of the information, but

10   indeed drowns out the information itself.

Vibration-state inference techniques have been described to determine downhole force and displacement at a position close to the bit from similar measurements at a second location in the drillstring, (see SPE 74718, Macpherson, et al., "Application and Analysis of Simultaneous Near Bit and Surface Dynamics

15   Measurements", SPE Drilling and Completions, Society of Petroleum Engineers, Dec. 2001). However, there is no suggestion therein of using such a technique for purposes of acoustic telemetry in a drillstring.

The methods of the present invention overcome the foregoing disadvantages of the prior art by providing a technique for removing a portion of the surface generated

20   noise thereby improving the signal to noise ratio of acoustic signals transmitted along a drill string.

SUMMARY OF THE INVENTION

In one aspect, a method of acoustic telemetry in a drill string in a wellbore,

25   comprises transmitting an acoustic signal related to a parameter of interest from a

transmitting location into the drill string. The signals propagated through the drill string are detected at a receiving location, where the detected signals include noise. A drill string transfer matrix is determined defining the propagation of signals through a transfer interval between the receiving location and the transmitting location. The

5   detected signals and the drill string transfer matrix are used for obtaining an estimate of the acoustic signal.

In another aspect, a method of reducing noise in an acoustic signal transmitted at a second location and received at a first location in a drill string, comprises calculating a transfer matrix related to a transmission interval of the drill string. Time

10   series data sets of vibrations are detected at the first location comprising a first time-series data set of measurements related to a force on the drill string and a second time-series data set of measurements related to an acceleration of the drill string. The first time-series data set and the second time-series data set are transformed to a frequency domain. The transformed first time-series data set and the transformed second time-

15   series data set are combined with the transfer function to generate an inferred force related signal at the second location and an inferred acceleration related signal at the second location. The inferred force related signal and the inferred acceleration related signal are transformed to the time domain generating an inferred time-series of force at the second location and an inferred time-series of acceleration at the second location.

20   Examples of the more important features of the invention thus have been summarized rather broadly in order that the detailed description thereof that follows may be better understood, and in order that the contributions to the art may be appreciated. There are, of course, additional features of the invention that will be described hereinafter and which will form the subject of the claims appended hereto.

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BRIEF DESCRIPTION OF THE DRAWINGS

For detailed understanding of the present invention, references should be made to the following detailed description of the preferred embodiment, taken in conjunction with the accompanying drawings, in which like elements have been given like

5   numerals, wherein:

Figure 1 is a schematic of a drilling system for use with a method according to one embodiment of the present invention;

Figure 2 is a block diagram of a frequency-domain method according to one embodiment of the present invention; and

10   Figure 3 is a block diagram of a time-domain method according to one embodiment of the present invention.

DESCRIPTION OF PREFERRED EMBODIMENTS

Referring now to Figure 1, a conventional drilling rig 2 is shown powering drill

15   string 4, which conventionally consists of multiple sections of drill pipe 6 and a bottomhole assembly 11. Sections 6 are connected to one another by tool joints 8 in the conventional manner. Drill bit 10 is connected at the bottom end of drill string 4, and can be a rotary bit, jet or spud bit, or other type of drill bit conventional in the art. As shown in Figure 1 drill bit 10 is connected to bottomhole assembly 11, which in turn is

20   connected to sections 6 of drill string 4. The bottomhole assembly 11 is typically made up of multiple sections (not shown) of drill collars having a substantially larger diameter than that of the drill pipe 6. Provision of such a bottomhole assembly 11 is conventional in the drilling art, and is useful for housing such equipment as detectors for sensing parameters of interest of the drilling operation and the surrounding

25   formation, as well as for other conventional functions. While such a bottomhole

assembly 11 is shown in **Figure 1**, it should be noted that the presence of bottomhole

assembly 11 is not required for purposes of the instant invention, such presence

depending upon the particular drilling operation being performed. However, for

purposes of acoustic telemetry as will be described hereinbelow, an acoustic transmitter

5   13 for vibrating drill string 4, according to information to be transmitted from

downhole to the surface, is preferably located in such a bottomhole assembly 11.

Alternatively, the acoustic transmitter 13 may be located at other locations in the drill

string 4.

In one preferred embodiment, the acoustic transmitter 13 excites axial vibration

10   modes. Alternatively, the acoustic transmitter may excite torsional vibration modes and

a combination of torsional and axial vibration modes. Such transmitter devices are

known in the art and will not be described here further.

Detector sub 12 is connected within drill string 4 near the surface of the earth.

Sub 12 contains detectors, such as force transducers, accelerometers, strain gages,

15   piezoelectric transducers, optical transducers, and the like, for detecting stress and

motion related to vibrations in drill string 4 and generating electrical signals

corresponding to the detected vibration-induced parameters. The electrical signals

generated from the detectors within sub 12 are communicated to computer system 19.

Computer system 19 analyzes the signals corresponding to the vibrations of drill string

20   4 to remove a portion of the unwanted noise signals to enable enhanced decoding of the

downhole transmitted information relating to the downhole measured data, according to

one preferred embodiment of the invention described hereinbelow.

The drill bit 10 generates vibrational noise as the bit 10 disintegrates the

formation. This noise propagates up the drill string 4 and mixes with the vibrationally

25   encoded data signal generated by transmitter 13. In addition, drilling rig noise is

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generated and transferred to the drill string 4 at the surface. Both the surface generated

noise and the downhole generated noise are received along with the data signal at sub

12. The method described below is useful in removing a portion of the surface

generated noise for enhancing detection of the data signal transmitted downhole. Other

5   techniques known in the art may be used for minimizing the downhole generated noise.

The present invention uses vibration-state inference to estimate the vibration

state at one location in the drill string from vibration measurements made at another

location in the same drill string. The objective is to remove the influence of unwanted

vibration sources (noise) on the measurements while correcting for changes made to the

10   signal by the transmission path (the drill string). In a typical preferred embodiment, the

measurement location is at the surface and the inference position is at the downhole

transmitter. Alternatively, in another preferred embodiment, for transmission of

command signals to a downhole tool, the surface may be the inferred position and the

measurements may be made at a downhole location.

15   Vibration-state inference requires determining both stress (either axial or

torsional), and motion in the drill string 4. The determination of stress (axial and

torsional) is commonly accomplished by determining a related strain with strain gages

(not shown) or force measuring devices known in the art. For purposes of the following

discussion and theoretical analysis, strain and stress are to be considered

20   interchangeable indications for stress in the drill string 4. The motion measurement

typically detects displacement, velocity, or acceleration of the drill string 4. Both axial

and torsional (or rotational) motions may be detected. One skilled in the art will

recognize that accelerometer and velocity measurements can be related to displacement

using common techniques. For purposes of the following discussion and theoretical

25   analysis, acceleration, displacement, and velocity are to be considered interchangeable

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indications for motion of the drill string 4.

Vibration-state inference relies on the knowledge of the mechanical system between the position of measurement and the position of inference, called the transmission interval, and the assumption that there is no externally applied excitation within the transmission interval. Of major utility is that the vibration-state inference technique does not depend on knowledge outside the transmission interval. Therefore, knowledge (or measurement) of the top and bottom boundary conditions (noise of the drill bit and surface equipment) of the drill string are not needed.

Theory:

The equation of motion for longitudinal vibrations of a uniform drill string is

$$\rho A \frac{\partial^2 u(x,t)}{\partial t^2} + \mu \frac{\partial u(x,t)}{\partial t} - E A \frac{\partial^2 u(x,t)}{\partial x^2} = 0 \tag{1}$$

Therefore,

$$\frac{\partial^2 u(x,t)}{\partial t^2} + \frac{\mu}{\rho A} \frac{\partial u(x,t)}{\partial t} - c_0{}^2 \frac{\partial^2 u(x,t)}{\partial x^2} = 0 \tag{2}$$

Where $c_0{}^2 = \dfrac{E}{\rho}$ (3)

In the above equations, function $u(x,t)$ represents the displacement, A the cross sectional area, ρ the mass density of the material of the drill string, μ the damping coefficient, c_0 the velocity of longitudinal waves and E is the Young's modulus.

Consider solutions of the form

$$u(x,t) = u_0(x)e^{j\omega t} \tag{4}$$

5   On substituting equation 4 in equation 3

$$\left[-\omega^2 + j\frac{\mu\omega}{\rho A}\right]u_0 - c_0^2 \frac{d^2u_0}{dx^2} = 0$$

$$\frac{d^2u_0}{dx^2} + \frac{\omega^2}{c_0^2}\left(1 - j\frac{\mu}{\rho A\omega}\right)u_0 = 0 \tag{5}$$

10

The unknown complex function $u_0(x)$ therefore satisfies the equation of the form

$$\frac{d^2u_0}{dx^2} + k^2 u_0 = 0 \tag{6}$$

15   where,

$$k^2 = \frac{\omega^2}{c_0^2}\left(1 - j\frac{\mu}{\rho A\omega}\right) \tag{7}$$

The solution of equation 6 is

20

$$u_0 = A_1 \sin(kx) + B_1 \cos(kx) \tag{8}$$

9

The force f_0 is given by

$$f_0 = E \, A \, \frac{\partial u_0}{\partial x} \tag{9}$$

5

$$= E \, A \, k \, [A_1 \cos(kx) - B_1 \, \sin(kx)] \tag{10}$$

Consider the following boundary conditions:

10   At the top $(x = 0)$, using equation 8, the displacement u_s is

$$u_s = u_0\big|_{x=0} = B_1 \tag{11}$$

and using equation 10, the force f_0 at $x = 0$ is

15

$$f_s = f_0\big|_{x=0} = E \, A \, k \, A_1 \tag{12}$$

Similarly, at a downhole location l feet away $(x = l)$, the displacement u_d is

20    $$u_d = u_0\big|_{x=l} = A_1 \sin(k \, l) + B_1 \, \cos(k l) \tag{13}$$

and the force f_d at $x = l$ is

$$f_d = f_0\big|_{x=l} = E\,A\,k\left[A_1\cos(kl) - B_1\sin(kl)\right] \tag{14}$$

The four equations 11 – 14 can be used to obtain the displacement and force (u_d & f_d)

at downhole location in terms of the measured displacement and force (u_s & f_s) at the

surface location as follows:

Substitute A_1 & B_1 from equations 11 & 12 into equation 13

$$u_d = \frac{1}{E\,A\,k}\sin(kl)\,f_s + \cos(kl)\,u_s \tag{15}$$

$$f_d = \cos(kl)\,f_s - E\,A\,k\sin(kl)\,u_s \tag{16}$$

From equation 4 it can be easily seen that the velocity (v) and acceleration (a) are given

by

$$v = \frac{du}{dt} = j\,\omega\,u_0(x)e^{j\omega t}$$

$$a = \frac{d^2u}{dt^2} = -\omega^2\,u_0(x)e^{j\omega t} \tag{17}$$

Equation 15 and 16 can therefore, be expressed in terms of velocity v_d & v_s as

$$v_d = \frac{j\,\omega}{E\,A\,k}\sin(kl)\,f_s + \cos(kl)\,v_s \tag{18}$$

11

$$f_d = \cos(kl)\, f_s \; - \; \frac{E\,A\,k}{j\,\omega}\sin(kl)\; v_s \qquad\qquad (19)$$

and, in terms of acceleration a_d & a_s as

$$a_d = \frac{-\omega^2}{E\,A\,k}\sin(kl)\, f_s \; + \; \cos(kl)\, a_s \qquad\qquad (20)$$

$$f_d = \cos(kl)\, f_s \; + \; \frac{E\,A\,k}{\omega^2}\sin(kl)\; a_s \qquad\qquad (21)$$

The above equations can be expressed in the matrix form as follows

$$\begin{bmatrix} u_d \\ f_d \end{bmatrix} = \begin{bmatrix} \cos(kl) & \dfrac{\sin(kl)}{E\,A\,k} \\ -E\,A\,k\sin(kl) & \cos(kl) \end{bmatrix}\begin{bmatrix} u_s \\ f_s \end{bmatrix} \qquad\qquad (22)$$

$$\begin{bmatrix} v_d \\ f_d \end{bmatrix} = \begin{bmatrix} \cos(kl) & \dfrac{j\,\omega}{E\,A\,k}\sin(kl) \\ -\dfrac{E\,A\,k}{j\,\omega}\sin(kl) & \cos(kl) \end{bmatrix}\begin{bmatrix} v_s \\ f_s \end{bmatrix} \qquad\qquad (23)$$

$$\begin{bmatrix} a_d \\ f_d \end{bmatrix} = \begin{bmatrix} \cos(kl) & \dfrac{-\omega^2}{E\,A\,k}\sin(kl) \\ \dfrac{E\,A\,k}{\omega^2}\sin(kl) & \cos(kl) \end{bmatrix}\begin{bmatrix} a_s \\ f_s \end{bmatrix} \qquad\qquad (24)$$

Equations 24 can be written in the following general form:

$$\begin{bmatrix} a_d \\ f_d \end{bmatrix} = \begin{bmatrix} T_{11} & T_{12} \\ T_{21} & T_{22} \end{bmatrix}\begin{bmatrix} a_s \\ f_s \end{bmatrix} \qquad\qquad (28)$$

where

$$T_{11} = T_{22} = \cos(kl), \quad T_{12} = -\frac{\omega^2}{EAk}\sin(kl) \quad \text{and} \quad T_{21} = \frac{EAk}{\omega^2} \sin(kl) \quad (28a)$$

5   In equation 24, the vector $\begin{bmatrix} a_d \\ f_d \end{bmatrix}$, which is a column matrix of acceleration

(displacement or velocity) and internal force, is known as the state vector. Equation 24

shows that the state vector at a surface location s is transferred to the state vector at the

downhole location d at distance l, through the square matrix, which is known as the

transfer matrix. It is a function of the elastic and dynamic properties of the drill string

10   system and frequency. Therefore, for known values of the state vector at the surface

and a chosen value of frequency, ω, it is possible to infer (or compute) the state vector

at the downhole location, for known properties of the drill string.

As is commonly known, a typical drill string comprises drill collars and drill

15   pipe sections with varying lengths and diameters. For a series of varying tubulars, each

characterized by its own transfer matrix, T_1, T_2, T_3, ... T_n, the transfer matrix

representing the effect of all the tubulars connected end-to-end is: $[T_n] \cdot [T_{n-1}] \cdot [T_{n-2}] \cdot$

$... \cdot [T_1]$. For the extreme ends of the transmission interval, for example end a and end b

with a system of n connected tubulars;

20    $$\begin{bmatrix} ub \\ Fb \end{bmatrix} = [[Tn] \cdots [T3][T2][T1]] \begin{bmatrix} ua \\ Fa \end{bmatrix} \quad (29)$$

Note that in matrix algebra $[A][B] \neq [B][A]$, therefore order is important in

calculating the system transfer matrix. The calculation starts multiplying transfer

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matrices from the inference end, not from the measurement end.

Sign convention:

Using a right handed coordinate system, with x axis coinciding with the axis of the tubular, the face with outward normal pointing in the positive direction of the x-axis, represents the positive face of the section. In this arrangement, the displacements are positive if they coincide with the positive direction of the coordinate system and forces are positive when acting on the positive face with vector direction pointing in the positive direction.

The results in equation 28 represent the transfer matrix for the case where the direction is from upper (or surface) to lower end (downhole), i.e. for estimating force and displacement at the lower end (downhole) using known (measured) forces and acceleration at the surface (or upper end). In essence, the signal transmitted from a downhole transmitter can be inferred from surface force and displacement measurements.

Evaluation of k:

From equation 7, k can be expressed as

$$k = \frac{\omega}{c_0} \sqrt{\left(1 - \frac{\mu}{\rho A \omega} j\right)} \tag{30}$$

It can be shown that (for example, see Kolsky, H., *Stress Waves in Solids*, Ch. 5, Dover Publications, Inc, 1963)

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$$\frac{\mu}{\rho A} = 2\alpha c_0 \qquad\qquad (31)$$

Where α is the attenuation coefficient. Also,

$$\alpha = \frac{\omega}{2Qc_0} \qquad\qquad (32)$$

On substituting equations 31 and 32 into equation 30 therefore

$$k = \frac{\omega}{c_0} \sqrt{\left(1 - \frac{1}{Q}j\right)} \qquad\qquad (33)$$

where Q is a quality factor representing the sharpness of a resonance peak of the vibrational system.

The solution to Equations 22-24 and equations 28 and 29 can be easily obtained using a computer using techniques known in the art.

The above inference-state analysis is directed to longitudinal (axial) vibrations, but is also valid for torsional vibrations by making the following substitutions into the above equations;

replace

E by G, the shear modulus;

u by θ, the angular displacement;

f by T, torque;

A by I_p, the polar moment of inertia; and

$c_t^2 = G/\rho$, the shear wave velocity.

15

Also note that the above analysis concerns steady-state conditions or frequency domain operations only. However, steady-state conditions are not required. Time-domain (arbitrary/non-periodic) signals may be analyzed as well if the initial (time zero) vibration state at the inference point is known. Many time-frequency domain

5 transformation algorithms, for example discrete Fourier transforms an Fast-Fourier transforms implicitly assume that the time data signal, or record, is periodic(i.e. that it repeats itself indefinitely). Real world signals, however, are commonly finite in length. Techniques are known in the art to deal with data that are not truly periodic while still enjoying the utility of digital transform methods. One method involves "windowing"

10 the finite length record. This technique essentially tapers the beginning and ending segments of the record such that it may be considered to be periodic. Various window functions are known in the art and include, but are not limited to, (i) Hanning, (ii) Hamming, and (iii) Blackman. The use of such techniques yield results for the finite length signal record that approximate the spectral characteristics of a periodic signal

15 with similar characteristics.

In a frequency domain operational example, shown in block diagram form in **Figure 2**, in **201**, downhole transmitter **13** imparts encoded data signals into the drill string **4** that travel through the drill string **4** toward the surface. In **202**, the drill string

20 acceleration a_s and drill string force f_s are measured at surface receiver **12** and input as time-series data to computer system **19** for analysis. In **203**, mechanical data, such as lengths and diameters, and mechanical properties, such as density and elastic modulus, are input for each drill string section between the measuring location and the downhole inference location at transmitter **13**. The mechanical data and mechanical properties are

25 used to compute a transfer matrix using the techniques described herein, see **204**. In

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205, the acceleration and force time-series data are transformed to the frequency

domain using techniques known in the art, such as the Fourier transform. In 206, the

transformed acceleration and force measurements are multiplied, in the frequency

domain, by the transfer matrix as described previously to calculate an inferred

5   acceleration and inferred force, in the frequency domain, at the downhole inference

location at transmitter 13. In 207, the frequency domain inferred downhole acceleration

and inferred downhole force are transformed back to the time domain using Fourier

transform, or equivalent techniques, thereby generating inferred acceleration and force

time-series data that can be decoded in step 208 to yield the downhole encoded and

10   transmitted data. The sequence described above relates to data sent from a downhole

location to a surface location but could also be used for transmitting data from a surface

location to a downhole location.

Alternatively, in a time domain operational example, shown in block diagram

form in **Figure 3**, in **301**, downhole transmitter 13 imparts encoded data signals into the

15   drill string 4 that travel through the drill string 4 toward the surface. In 302, the drill

string acceleration a_s and drill string force f_s are measured at surface receiver 12 and

input as time-series data to computer system 19 for analysis. In 303, mechanical data,

such as lengths and diameters, and mechanical properties, such as density and elastic

modulus, are input for each drill string section between the measuring location and the

20   downhole inference location at transmitter 13. The mechanical data and mechanical

properties are used to compute a transfer matrix using the techniques described herein,

see 304. In 305, the frequency dependent transfer matrix is transformed to the time

domain using techniques known in the art, such as the Fourier transform. One skilled in

the art will appreciate that just as the time domain signal must be shaped or windowed

25   to provide acceptable results, so to the frequency signal must be shaped, for example,

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by band-limiting the Fourier coefficients. This ensures that the resultant operator is sufficiently tapered to accurately approximate a periodic signal, when transformed. In 306, the acceleration and force measurements are combined with the transfer matrix using standard convolution methods to calculate an inferred acceleration and inferred

5   force, in the time domain, at the downhole inference location at transmitter 13, thereby generating inferred acceleration and force time-series data that can be decoded in step 207 to yield the downhole encoded and transmitted data. The sequence described above relates to data sent from a downhole location to a surface location but could also be used for transmitting data from a surface location to a downhole location.

10   A major advantage in using the transfer matrix method is that a large, complex system can be broken down into its components which have simple elastic and dynamic properties. Calculations can be then made, by proceeding from one component to the other, starting from one end of the first component to the next and so on. In a drill string, the components can be drill pipes, drill collars, etc. with different dimensions

15   and material properties. This technique is computationally more efficient than solving such a system using other common techniques such as finite element methods.

          In the method discussed above, it has been shown (using equation 24) that it is possible to infer or estimate the motion (i.e. displacement, velocity or acceleration) and force (or stress) at one location from known (measured) motion and stress at another

20   location thereby enabling improved acoustic drill string telemetry. The knowledge of boundary conditions or noise sources outside the interval between the measurement point and the inference point is not needed.

          The foregoing description is directed to particular embodiments of the present invention for the purpose of illustration and explanation. It will be apparent, however,

25   to one skilled in the art that many modifications and changes to the embodiment set

forth above are possible without departing from the scope and the spirit of the invention. It is intended that the following claims be interpreted to embrace all such modifications and changes.

What is claimed is:

1 1. A method of acoustic telemetry in a drill string in a wellbore, comprising:

2   a. transmitting an acoustic signal related to a parameter of interest from a

3   transmitting location into the drill string;

4   b. detecting signals propagated through the drill string at a receiving

5   location, said detected signals including noise;

6   c. determining a drill string transfer matrix defining the propagation of

7   signals through a transfer interval between the receiving location and the

8   transmitting location; and

9   d. using said detected signals and the drill string transfer matrix for

10   obtaining an estimate of the acoustic signal.

1 2. The method of claim 1 wherein detecting signals at a receiving location

2 comprises detecting a first time-series of measurements related to a force on said drill

3 string and a second time-series of measurements related to a motion of said drill string.

1 3. The method of claim 2 wherein using said detected signals and the drill string

2 transfer matrix for obtaining an estimate of the acoustic signal comprises:

3   a. transforming said first time-series of measurements and said second

4   time-series of measurements to a frequency domain;

5   b. combining said transformed first time-series of measurements and said

6   transformed second time-series measurements with said transfer matrix

7   to generate an inferred force related signal at said second location and an

8   inferred motion related signal at said second location;

9   c. transforming said inferred force related signal and said inferred motion

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10   related signal to the time domain generating an inferred time-series force

11   at said second location and an inferred time-series motion at said second

12   location; and

13   d.   decoding said inferred force signal and said inferred motion signal to

14   determine said transmitted parameter of interest.

1   4.   The method of claim 1 wherein determining the drill string transfer matrix

2   comprises:

3   i.   inputting data related to mechanical properties and material properties

4   for each of a plurality of sections of the drill string;

5   ii.   calculating for each of the plurality of sections of the drill string, a

6   transfer matrix related to each section of the drill string; and

7   iii. combining each of the plurality of section transfer matrices with each

8   succeeding section transfer matrix.

1   5.   The method of claim 1 wherein the transmitting location is a downhole location

2   proximate a bottom end of the drill string and said receiving location is proximate a top

3   end of the drill string.

1   6.   The method of claim 1 wherein the transmitting location is proximate a top end

2   of the drill string and the receiving location is downhole proximate a bottom end of the

3   drill string.

1   7.   The method of claim 2, wherein the measurement related to drill string motion

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2   is one of (i) an acceleration, (ii) a velocity, and (iii) a displacement.

1   8.   The method of claim 2 wherein using said detected signals and the drill string

2   transfer matrix for obtaining an estimate of the acoustic signal comprises:

3   i.   transforming said transfer matrix to a time domain;

4   ii.   combining said first time-series of measurements and said second time-

5   series of measurements with said transformed transfer matrix to generate

6   an inferred force related signal at said second location and an inferred

7   motion related signal at said second location; and

8   iii.   decoding said inferred force signal and said inferred motion signal to

9   determine said transmitted parameter of interest.

1   9.   The method of claim 3, wherein the step of transforming said first time-series of

2   measurements and said second time-series of measurements includes windowing said

3   first time-series of measurements and said second time-series of measurements.

1   10.   The method of claim 3, wherein the step of transforming said inferred force

2   related signal and said inferred motion related signal to the time domain includes band-

3   limiting said inferred force related signal and said inferred motion related signal in the

4   frequency domain before transformation to the time domain.

1   11.   A method of reducing noise in an acoustic signal transmitted at a second

2   location and received at a first location in a drill string, comprising:

3   a.   calculating a transfer matrix related to a transmission interval of the drill

22

4   string;

5   b.   detecting time series data sets of vibrations at said first location

6   comprising a first time-series data set of measurements related to a

7   force on said drill string and a second time-series data set of

8   measurements related to an acceleration of said drill string;

9   c.   transforming said first time-series data set and said second time-series

10   data set to a frequency domain;

11   d.   combining said transformed first time-series data set and said

12   transformed second time-series data set with said transfer function to

13   generate an inferred force related signal at said second location and an

14   inferred acceleration related signal at said second location; and

15   e.   transforming said inferred force related signal and said inferred

16   acceleration related signal to the time domain generating an inferred

17   time-series of force at said second location and an inferred time-series of

18   acceleration at said second location.

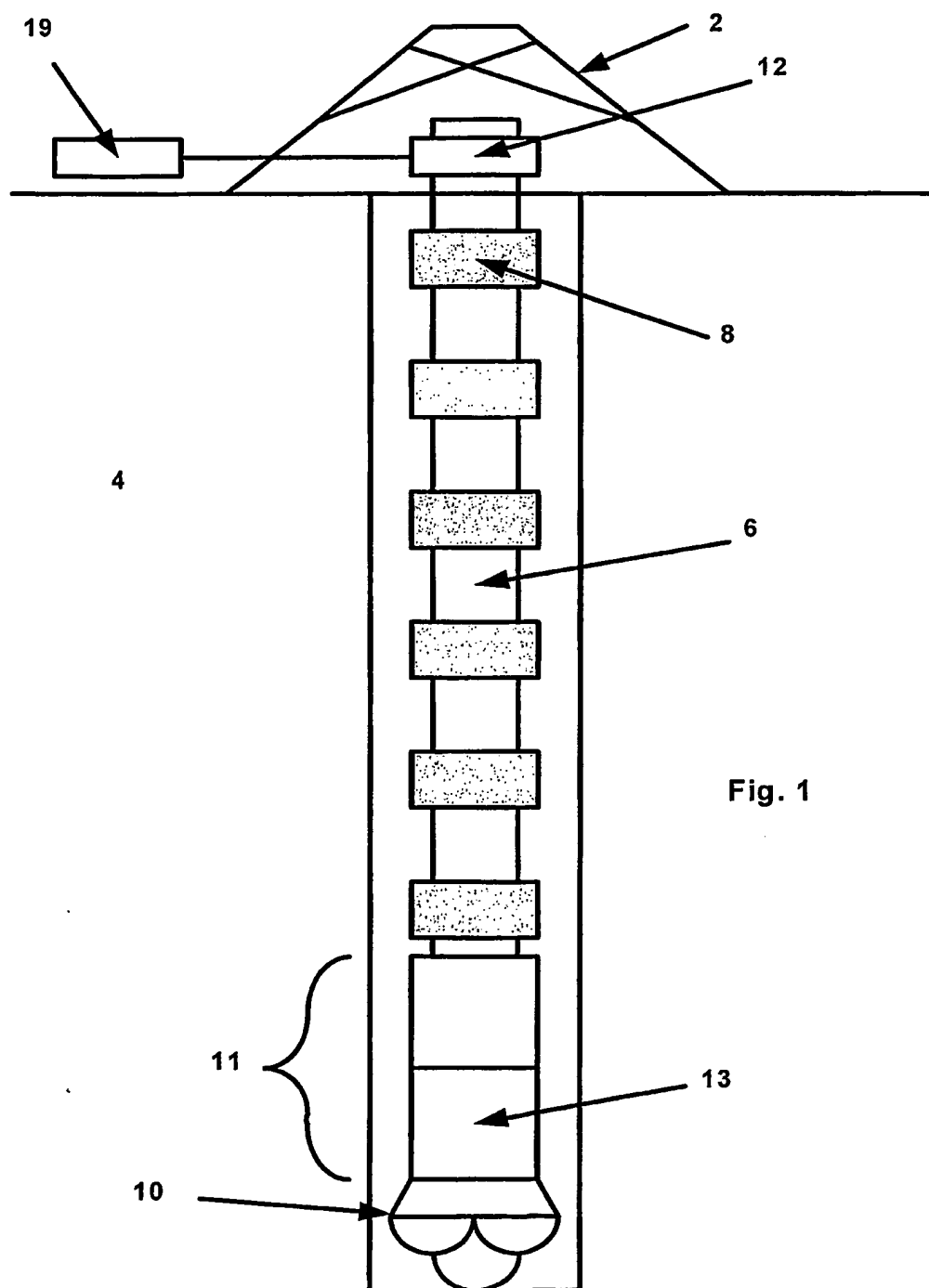1   12.   The method of claim 11 wherein calculating the drill string transfer matrix

2   comprises:

3   i.   calculating for each of a plurality of drill string sections, a transfer

4   matrix related to each section of the drill string; and

5   ii. combining each of the plurality of section transfer matrices with each

6   succeeding section transfer matrix.

1   13.   The method of claim 11 wherein the second transmitting location is a downhole

2   location proximate a bottom end of the drill string and said first receiving location is

3   proximate a top end of the drill string.

1   14.   The method of claim 11 wherein the second transmitting location is proximate a

2   top end of the drill string and the first receiving location is downhole proximate a
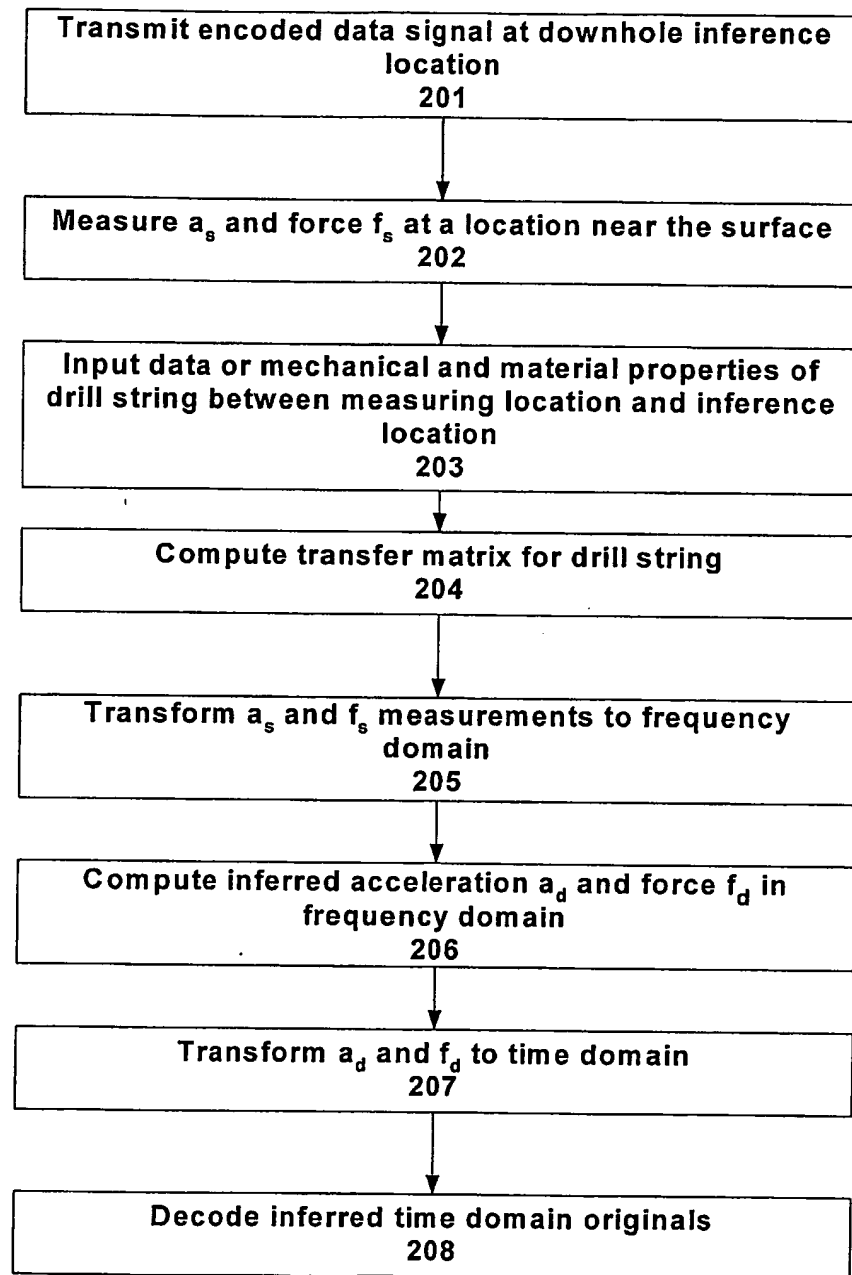
3   bottom end of the drill string.

Fig. 1

Transmit encoded data signal at downhole inference
location
201

Measure a_s and force f_s at a location near the surface
202

Input data or mechanical and material properties of
drill string between measuring location and inference
location
203

Compute transfer matrix for drill string
204

Transform a_s and f_s measurements to frequency
domain
205

Compute inferred acceleration a_d and force f_d in
frequency domain
206

Transform a_d and f_d to time domain
207

Decode inferred time domain originals
208

Fig. 2

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┌─────────────────────────────────────────────────┐
│   Transmit encoded data signal at downhole inference│
│                    location                      │
│                      301                         │
└─────────────────────────────────────────────────┘
                         │
                         ▼
┌─────────────────────────────────────────────────┐
│   Measure $a_s$ and force $f_s$ at a location near the surface│
│                      302                         │
└─────────────────────────────────────────────────┘
                         │
                         ▼
┌─────────────────────────────────────────────────┐
│   Input data or mechanical and material properties of│
│   drill string between measuring location and inference│
│                    location                      │
│                      303                         │
└─────────────────────────────────────────────────┘
                         │
                         ▼
┌─────────────────────────────────────────────────┐
│        Compute transfer matrix for drill string  │
│                      304                         │
└─────────────────────────────────────────────────┘
                         │
                         ▼
┌─────────────────────────────────────────────────┐
│        Transform transfer matrix into time domain│
│                      305                         │
└─────────────────────────────────────────────────┘
                         │
                         ▼
┌─────────────────────────────────────────────────┐
│   Compute time domain inferred acceleraton $a_d$ or force│
│   $f_d$ by convolving the time domain transfer matrix with│
│   the time domain surface measurements of acceleration│
│                $a_s$ and force $f_s$             │
│                      306                         │
└─────────────────────────────────────────────────┘
                         │
                         ▼
┌─────────────────────────────────────────────────┐
│        Decode inferred time domain originals     │
│                      307                         │
└─────────────────────────────────────────────────┘
```
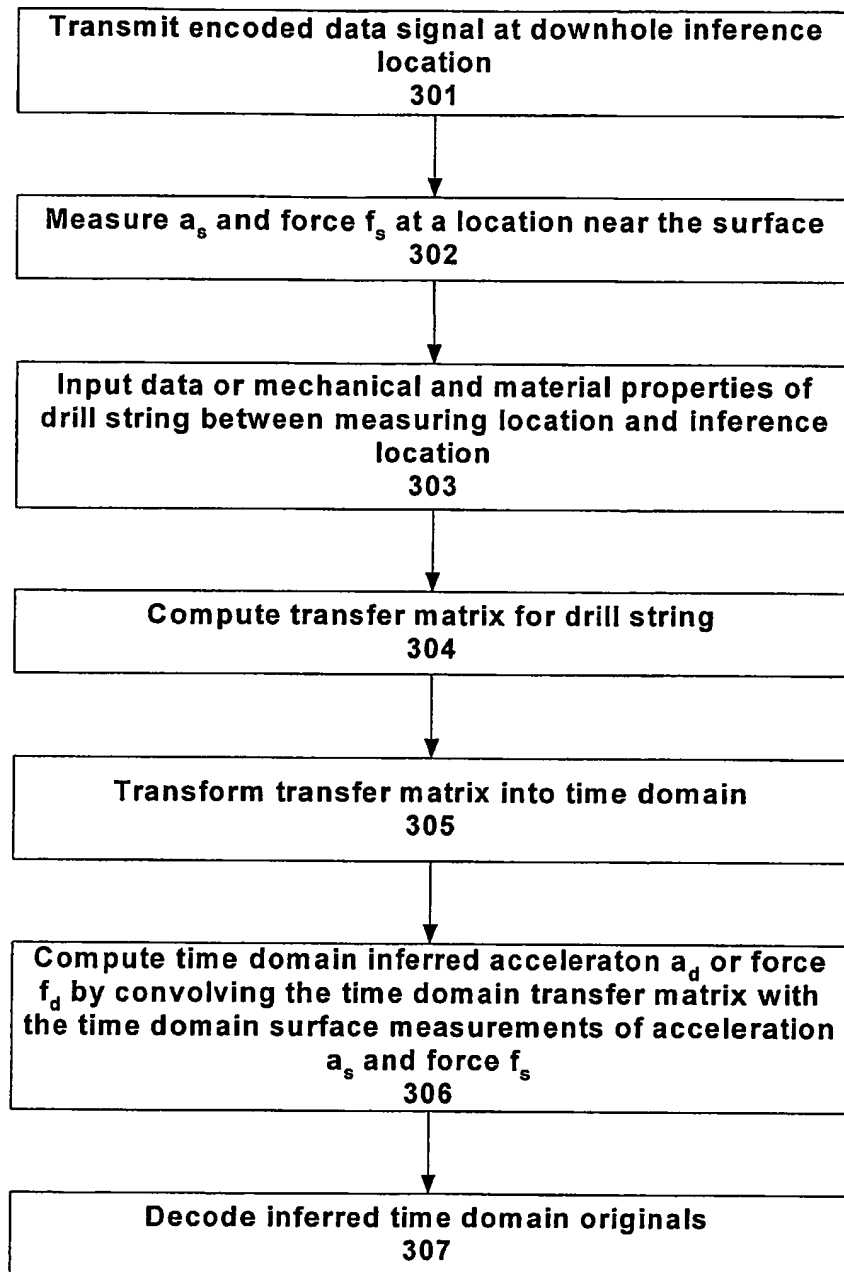
Fig. 3

INTERNATIONAL SEARCH REPORT

A. CLASSIFICATION OF SUBJECT MATTER
IPC 7   G01V11/00   E21B47/16

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
IPC 7   G01V   E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EPO-Internal, WPI Data, PAJ, INSPEC, COMPENDEX

C. DOCUMENTS CONSIDERED TO BE RELEVANT

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[X] Further documents are listed in the continuation of box C.   [X] Patent family members are listed in annex.

Date of the actual completion of the international search	Date of mailing of the international search report
5 September 2003	22/09/2003

Name and mailing address of the ISA European Patent Office, P.B. 5818 Patentlaan 2 NL – 2280 HV Rijswijk Tel. (+31-70) 340-2040, Tx. 31 651 epo nl, Fax: (+31-70) 340-3016	Authorized officer De Bekker, R

C.(Continuation) DOCUMENTS CONSIDERED TO BE RELEVANT		
Category °	Citation of document, with indication,where appropriate, of the relevant passages	Relevant to claim No.
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